CLIMATE LEADERS

GREENHOUSE GAS INVENTORY PROTOCOL CORE MODULE GUIDANCE

Direct Emissions from
Stationary Combustion Sources

CLIMATE LEADERS
U.S. Environmental Protection Agency

The Climate Leaders Greenhouse Gas Inventory Protocol is based on the Greenhouse Gas Protocol (GHG Protocol) developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). The GHG Protocol consists of corporate accounting and reporting standards and separate calculation tools. The Climate Leaders Greenhouse Gas Inventory Protocol is an effort by EPA to enhance the GHG Protocol to fit more precisely what is needed for Climate Leaders. The Climate Leaders Greenhouse Gas Protocol consists of the following components:

■ Design Principles Guidance

■ Core Modules Guidance

■ Optional Modules Guidance

All changes and additions to the GHG Protocol made by Climate Leaders are summarized in the Climate Leaders Greenhouse Gas Inventory Protocol Design Principles Guidance.

For more information regarding the Climate Leaders Program, visit us on the web at www.epa.gov/climateleaders.

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Introduction

Combustion of fossil fuels in stationary combustion sources results in the following greenhouse gas (GHG) emissions: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Sources of emissions from stationary combustion include boilers, heaters, furnaces, kilns, ovens, flares, thermal oxidizers, dryers, and any other equipment or machinery that combusts carbon bearing fuels or waste streams.

This document presents guidance for estimating direct GHG emissions resulting from stationary (non-transport) combustion of fossil fuels at owned/operated sources. This guidance applies to all companies whose operations involve stationary combustion of fossil fuel.

1.1. Greenhouse Gases Included

The three GHGs—CO_2, CH_4, and N_2O—are emitted during the combustion of fossil fuels. CO_2 accounts for the majority of the GHG emissions from stationary combustion sources. In the U.S., CO_2 emissions represent over 99% of the total CO_2-equivalent[1] GHG emissions from all commercial, industrial, and electricity generation and industrial stationary combustion sources. CH_4 and N_2O emissions together represent less than 1% of the total CO_2-equivalent emissions from the same sources[2].

Given the relative emissions contributions of each gas, CH_4 and N_2O emissions are often excluded by assuming that they are "not material". However, as outlined in Chapter 1 of the

Climate Leaders Design Principles, the materiality of a source can only be established after it has been assessed. This does not necessarily require a rigorous quantification of all sources, but at a minimum, an estimate based on available data should be developed for all sources and categories of GHGs, and included in a Partner's GHG inventory.

The approach to estimate CO_2 emissions from stationary combustion sources varies significantly from the approach to estimate CH_4 and N_2O emissions. While CO_2 can be reasonably estimated by applying an appropriate carbon content and fraction of carbon oxidized factor to the fuel quantity consumed, estimating CH_4 and N_2O depends not only upon fuel characteristics, but also on technology type and combustion characteristics, usage of pollution control equipment, and ambient environmental conditions. Emissions of these gases also vary with the size, efficiency, and vintage of the combustion technology, as well as maintenance and operational practices. Due to this complexity, a much greater effort is required to estimate CH_4 and N_2O emissions from stationary sources, and a much higher level of uncertainty exists.

Due to the relative emission contribution of each gas and the complexity involved in estimating CH_4 and N_2O emissions, this document primarily deals with guidance for estimating CO_2 emissions from stationary combustion sources. The guidance on estimating CH_4 and N_2O emissions is limited to the screening approach in Section 3 and the associated set of

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1 See Chapter 6 of the *Climate Leaders Design Principles* document for a discussion of CO_2-equivalents.

2 Tables 3-3, 3-16, & 3-17 of U.S. EPA *2007 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005*, EPA430-R-07-002, April 2007.

default emission factors. However, for Partners that wish to examine CH_4 and N_2O emissions from stationary combustion sources in more detail, a list of references for estimating these emissions is included in Appendix A.

1.2. Biofuels

Non-fossil carbon bearing fuels (e.g., wood and wood waste, etc.) may also be combusted in stationary sources. The CO_2 emissions from combustion of these fuels are treated as biomass CO_2 emissions. Partners are required to list biomass CO_2 emissions in terms of total amount of gas emitted as part of their Climate Leaders reporting requirements. However, biomass CO_2 emissions are not included in the overall CO_2-equivalent emissions inventory used to track Partners' progress towards their Climate Leaders reduction goal. This is because it is assumed that combustion of biofuels do not contribute to net addition of CO_2 to the atmosphere[3].

1.3. Waste Fuels

Waste products in solid, liquid, and gaseous form may be combusted in stationary sources as well. Typical waste products include, but are not limited to, used tires, used motor oils, municipal solid waste (MSW), hazardous waste, landfill gas, and by-product gases. These waste fuels are treated like any other fuels in a Partner's inventory. Therefore, any GHG produced from combustion of a fossil-based waste product is reported in a Partner's inventory. Any CO_2 emissions from combustion of a non-fossil waste are listed as biomass CO_2 as described in Section 1.2. This applies to

entire waste streams or portions of the waste stream. For example, the CO_2 produced from combusting the biomass portion of MSW (e.g., yard waste, paper products, etc.) is reported as biomass CO_2. The CO_2 produced from combusting the fossil portion of the MSW (e.g., plastics, etc.) is reported as CO_2 and is included in a Partner's inventory.

Emissions from waste fuels only include the actual emissions from the combustion process and do not include any "offsets" from use of the waste fuel. Future guidance may be developed around offsets obtained from the burning of waste fuels and they would be included in the Climate Leaders Optional Module on offsets. These offsets would be reported separately on a Partner's Climate Leaders inventory.

1.4. Non-Combustion Emission Sources

The combustion of fuel does not account for all GHG emissions from stationary combustion sources. For example, use of natural gas may result in fugitive methane emissions from leaking gas transportation lines owned by the Partner. Storage of fuels may also result in fugitive emissions, for example, VOC emissions from fuel storage tanks (often regarded as a significant VOC source in air pollution studies) and methane emissions from coal piles. Typically these sources are minor compared to CO_2 combustion emissions, however, Partners should account for these non-combustion sources. Climate Leaders guidance on estimating these other sources will be developed as necessary.

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3 This assumes that there is no net loss of biomass-based carbon associated with the land use practices used to produce these fuels, U.S. EPA *2007 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005*, EPA430-R-07-002, April 2007.

Methods for Estimating CO$_2$ Emissions

There are two main methods for estimating CO$_2$ emissions from stationary combustion sources:

■ Direct measurement

■ Analysis of fuel input

Direct measurement of CO$_2$ emissions is performed through the use of a Continuous Emissions Monitoring System (CEMS). Fuel analysis is essentially a mass balance approach where carbon content and carbon oxidation factors are applied to fuel input to determine emissions. Both methods are described in more detail in the following sections.

2.1. Use of Continuous Emissions Monitoring System (CEMS) Data

Continuous emissions monitoring is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. Several U.S. EPA regulatory programs (e.g., Acid Rain Program, New Source Performance Standards, and Maximum Available Control Technology Standards) have provisions regarding CEMS.

CEMS can be used to measure CO$_2$ emissions. Title IV of the U.S. Clean Air Act requires owners or operators of electricity generating units to report CO$_2$ emissions from affected units under the Acid Rain Program[4]. 40 CFR Part 75 which establishes requirements for the monitoring, recordkeeping, and reporting from affected units under the Acid Rain Program outlines two approaches for determining CO$_2$ emissions using CEMS (see Appendix F of 40 CFR Part 75):

■ A monitor measuring CO$_2$ concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO$_2$ mass emissions. Annual CO$_2$ emissions are determined based on the operating time of the unit.

■ A monitor measuring O$_2$ concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas combined with theoretical CO$_2$ and flue gas production by fuel characteristics can be used to determine CO$_2$ flue gas emissions and CO$_2$ mass emissions. Annual CO$_2$ emissions are determined based on the operating time of the unit.

If a Partner has reported quality assured CO$_2$ emissions data from one of the above CEMS approaches to satisfy their Title IV requirements, they should report these same CO$_2$ emissions directly to the Climate Leaders program. Partners that collect CO$_2$ emissions data from a CEMS that does not conform to the specific requirements prescribed under 40 CFR Part 75 should use the fuel analysis approaches outlined in Section 2.2 below, or may request that Climate Leaders review the CEMS data as provided in Chapter 6 of the *Climate Leaders Design Principles*.

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4 Units over 25 megawatts and new units under 25 megawatts that use fuel with a sulfur content greater than 0.05 percent by weight are required to measure and report sulfur dioxide (SO$_2$), nitrogen oxide (NO$_X$), and CO$_2$ emissions under the U.S. EPA's Acid Rain Program.

2.2. Fuel Analysis Approach

The fuel analysis approach to estimate CO_2 emissions involves determining a carbon content of fuel combusted and applying that to the amount of fuel burned to get CO_2 emissions.

For affected units under the Acid Rain Program, 40 CFR Part 75 (Appendix G) describes fuel analysis methods for calculating CO_2 emissions based on the measured carbon content of the fuel, adjusted for any unburned carbon, and the amount of fuel combusted[5].

If a Partner is measuring and reporting CO_2 emissions under their Title IV requirements using the fuel analysis methods outlined in 40 CFR Part 75, they should report these same CO_2 emissions results directly to the Climate Leaders program.

For Partners not reporting CO_2 emissions under the Acid Rain Program, this guidance provides a default fuel analysis approach that Partners should use to calculate their CO_2 emissions. The default approach uses carbon content factors that are based on energy units as opposed to mass or volume units. Carbon content factors based on energy units are less variable than carbon content factors per mass or volume units because the heat content or energy value of a fuel is more closely related to the amount of carbon in the fuel than to the total physical quantity of fuel. Carbon content factors stated in terms of carbon per energy of the fuel are generally less variable than those expressed in terms of mass or volume so there is less chance for error (see Section 5).

Equation 1 presents an overview of the default fuel analysis approach. Fuel types with default heat contents, carbon content coefficients, and fraction-oxidized factors are listed in Appendix B. This method can be applied using the emission factors provided or using custom coefficients. The steps involved with estimating CO_2 emissions with the fuel analysis approach are shown on the following page.

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5 Units reporting CO_2 emissions under the Acid Rain Program, through either the CEMS or fuel analysis approach, are required to include CO_2 emissions from sorbent use (e.g., limestone used in flue gas desulfurization equipment). Partners not required to report under the Acid Rain Program should be sure to include any CO_2 emissions from sorbent use in their Climate Leaders inventory. Procedures to estimate these emissions are outlined in 40 CFR Part 75 Appendix G, Section 3.

Equation 1: Fuel Analysis Approach for Estimating CO_2 Emissions

$$\text{Emissions} = \sum_{i=1}^{n} \text{Fuel}_i \times \text{HC}_i \times \text{C}_i \times \text{FO}_i \times \frac{\text{CO}_{2\,(\text{m.w.})}}{\text{C}_{(\text{m.w.})}}$$

where:

Fuel_i	=	Mass or Volume of Fuel Type i Combusted
HC_i	=	Heat Content of Fuel Type i $\left(\dfrac{\text{energy}}{\text{mass or volume of fuel}}\right)$
C_i	=	Carbon Content Coefficient of Fuel Type i $\left(\dfrac{\text{massC}}{\text{energy}}\right)$
FO_i	=	Fraction Oxidized of Fuel Type i
CO_2 (m.w.)	=	Molecular weight of CO_2
C (m.w.)	=	Molecular Weight of Carbon

Step 1: Determine the amount of fuel combusted. This can be based on fuel receipts, purchase records, or through direct measurement at the combustion device. If purchase records are used, care should be taken to subtract out fuel used to produce feedstocks or materials such as plastics where the carbon is ultimately stored. Section 5.1 describes in more detail the different sources that can be used to determine amount of fuel combusted.

Step 2: Convert the amount of fuel combusted into energy units. As discussed in Section 5.2, the amount of fuel combusted is measured in terms of physical units (e.g., mass or volume). This needs to be converted to amount of fuel used in terms of energy units in order to apply the default carbon content coefficients. The heating value of purchased fuel is often known and provided by the fuel supplier because it is directly related to the useful output or value of the fuel. Heating value can also be determined by fuel sampling and analysis.* If heating value data is available, either from the fuel supplier or sampling and analysis results, then that data should be used. If this is not the case then default fuel specific heating values listed in Appendix B can be applied.

Step 3: Estimate carbon content of fuels consumed. To estimate the carbon content, multiple energy content for each fuel by fuel-specific carbon content coefficients (mass C/energy). Carbon content can also be determined by fuel sampling and analysis.* If carbon content data is available, either from the fuel supplier or sampling and analysis results, then that data should be used. U.S. average default carbon content coefficients are provided in Appendix B if fuel specific data is not available from the fuel supplier or sampling and analysis.

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* Fuel sampling and analysis should be performed periodically with the frequency dependant on the type of fuel. The sampling frequency should be greater for more variable fuels (e.g., coal, wood, sold waste) than for more homogenous fuels (e.g., natural gas, diesel fuel). The sampling and analysis methodologies used should be detailed in the Partners IMP. Refer to 40 CFR Part 75, Appendix G for recommended sampling rates and methods.

Example CO$_2$ Calculation

A Climate Leaders Partner has an on-site natural gas boiler. The Partner does not meter the gas that enters the boiler directly. However, the Partner does have a record of the natural gas utility bills for the annual reporting period in question. The bills list the amount of fuel purchased in terms of energy (e.g., therms) as well as the cubic feet of gas purchased and the heating value of the gas. It is assumed that there are no fugitive releases of gas, there is no inventory of natural gas stored on-site, and that all the natural gas purchased is combusted (i.e., no feedstock use of gas). The following information is available from the fuel supplier:

Month	Amount of Gas Purchased (scf)	Heat Content (Btu/scf)	Amount of Gas Purchased (therms)
January	550,000	1,025	5,637.5
February	580,000	1,025	5,945
March	530,000	1,025	5,432.5
April	480,000	1,025	4,920
May	500,000	1,025	5,125
June	490,000	1,025	5,022.5
July	510,000	1,025	5,227.5
August	390,000	1,025	3,997.5
September	480,000	1,025	4,920
October	540,000	1,025	5,535
November	490,000	1,025	5,022.5
December	460,000	1,025	4,715
Total	**6,000,000**		**61,500**

Note: scf = standard cubic feet, 1 therm = 100,000 Btu

Steps 1 & 2 are combined in that the fuel supplier has already converted fuel use into energy units based on a fuel specific heating value as shown in the table above.

Step 3 calls for estimating the amount of carbon in the fuel consumed. The default factor provided in Appendix B is used for this calculation.

   Default factor = 14.47 (kg Carbon/mmBtu)
   Converting the annual gas data: 61,500 therms × 0.1 mmBtu/therm = 6,150 mmBtu
   Multiply by the default carbon content coefficient: 6,150 mmBtu × 14.47 kg C/mmBtu = 88,990.5 kg C

Step 4 is to account for the small portion of carbon in the fuel that is not oxidized. The default factor provided in Appendix B is used, which equals 1.00. The result of Step 4 is the amount of carbon in the fuel that is oxidized into CO$_2$.

   Multiply the result of Step 3 by the carbon oxidation factor: 88,990.5 kg C × 1.00 = 88,990.5 kg C

Step 5 multiplies the amount of carbon released by the molecular weight ratio of CO$_2$ to carbon (44/12), in order to calculate the mass of CO$_2$ emissions.

   88,990.5 kg C × (44/12) kg CO$_2$/kg C = 326,298.5 kg CO$_2$
        OR
   326 metric tons of CO$_2$ emissions for the reporting year in question.

Step 4: Estimate carbon emitted. When fuel is burned, most of the carbon is eventually oxidized to CO_2 and emitted to the atmosphere. To account for the small fraction that is not oxidized and remains trapped in the ash, multiply the carbon content by the fraction of carbon oxidized. The amount of carbon oxidized is assumed to be 100 per-cent unless specific supplier information is available.

Step 5: Convert to CO_2 emitted. To obtain total CO_2 emitted, multiply carbon emissions by the molecular weight ratio of CO_2 (m.w. 44) to carbon (m.w. 12) (44/12).

Methods for Estimating CH$_4$ and N$_2$O Emissions

The basic calculation procedure for estimating CH$_4$ and N$_2$O emissions from stationary combustion is represented by Equation 2.

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Equation 2: Estimation Method for CH$_4$ and N$_2$O Emissions

$$\text{Emissions}_{p,s} = A_s \times EF_{p,s}$$

where,

p = Pollutant (CH$_4$ or N$_2$O)

s = Source Category

A = Activity Level

EF = Emission Factor

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For both pollutants, the source category varies depending on the level of detail attained in analyzing fuel use data. As mentioned, CH$_4$ and N$_2$O emissions depend not only on the fuel characteristics but also on the combustion technology type, combustion characteristics, and control technologies. At the lowest level of detail, emissions can be calculated by knowing the type of fuel. A more detailed approach would use fuel type and sector (utilities, industrial use, etc.). At the highest level of detail, calculations would use information on fuel type and specific type of combustion equipment.

Appendix A provides a set of default factors for calculating CH$_4$ and N$_2$O emissions from stationary combustion sources. The default factors provided are in terms of fuel type and by sector of where the fuel is consumed. It is recommended that these factors be used primarily as a screening approach to determine the magnitude of CH$_4$ and N$_2$O emissions in relationship to CO$_2$ emissions from stationary combustion. If it is determined that CH$_4$ and N$_2$O are a significant source of GHG emissions from stationary combustion, it is recommended that the Partner look into more specific emissions factors. Appendix A lists several sources where more specific emission factors can be found.

The activity level used to estimate emissions of CH$_4$ and N$_2$O depends on the type of emission factor used and could be in terms of fuel input (mass, volume, or energy) to a source category. The default factors provided in Appendix A are in terms of emissions per fuel energy input to a category of fuel use. Fuel energy input data is often tracked as part of determining CO$_2$ emissions from stationary combustion sources and can also be used to estimate CH$_4$ and N$_2$O emissions with the factors provided in Appendix A.

Example CH$_4$ and N$_2$O Calculation

From the previous example, a Partner uses 6,150 mmBtu of natural gas per year. The emissions factors from Appendix A can be applied to estimate emissions of CH$_4$ and N$_2$O. Appendix A lists several different emissions factors for different fuels and different end-use sectors, the industrial end-use sector for natural gas fuel is chosen to best represent this example.

For CH$_4$, 6,150 mmBtu × 4.75 g CH$_4$/mmBtu = 29,213 g or 29.2 kg of CH$_4$ emissions

For N$_2$O, 6,150 mmBtu × 0.095 g N$_2$O/mmBtu = 584 g or 0.584 kg of N$_2$O emissions

Global Warming Potentials (GWPs) of 21 and 310 can then be applied to the CH$_4$ and N$_2$O emissions respectively. See Chapter 6 of the *Climate Leaders Design Principles* for more discussion on GWPs. These emissions can then be compared to the CO$_2$ emissions from the same source as calculated in the previous example.

29.2 kg of CH$_4$ × 21 = 613 kg or 0.613 metric tons of CO$_2$-equivalent emissions

0.584 kg of N$_2$O × 310 = 181 kg or 0.181 metric tons of CO$_2$-equivalent emissions

Therefore, the total CO$_2$-equivalent emissions for natural gas stationary combustion of the reporting entity, including the CO$_2$ emissions from the previous example = 326 metric tons. The contribution of CH$_4$ and N$_2$O emissions combined is less than 0.25% of the total GHG emissions. The Partner includes this estimate of CH$_4$ and N$_2$O emissions in their inventory and does not need to consider any further detail of CH$_4$ and N$_2$O emission factors (e.g., by specific combustion device).

Choice of Method for Calculating CO_2 Emissions

Partners reporting CO_2 emissions data to the U.S. EPA under Title IV of the Clean Air Act, primarily electricity generating units, can report the same emissions data to the Climate Leaders program. The CO_2 emissions can be determined using any of the methods outlined in 40 CFR Part 75 (e.g. CEMS or fuel analysis approach). If the CO_2 data is deemed to be quality assured and is accepted to satisfy a Partners Title IV requirements then this data should be reported as part of their GHG inventory under the Climate Leaders program.

For Partners not currently reporting CO_2 data to the U.S. EPA under Title IV of the Clean Air Act, the choice of method depends on data availability. If a CEMS is installed or if the fuel characteristic data is available from sampling, the Partner may use the fuel analysis methods outlined in 40 CFR Part 75 (Appendix G) to calculate CO_2 emissions and report this data to Climate Leaders. If there is not CEMS or sampling data available that will allow the fuel analysis methods outlined in 40 CFR Part 75 to be used, the Partner should use the default fuel analysis methods outlined in this guidance. CO_2 emissions data from CEMS other than those used to report under Title IV of the Clean Air Act, or from other generally accepted CO_2 estimation protocols for stationary sources may be accepted by Climate Leaders as part of a Partners GHG inventory. See Chapter 6 of the *Climate Leaders Design Principles* for acceptance of data from procedures not specifically provided under the *Climate Leaders GHG Inventory Protocol Core Module guidance documents*.

Choice of Activity Data and Emission Calculation Factors

This section discusses choices of activity data and factors used for calculating CO_2 emissions with the default fuel analysis approach provided in Section 2.2. This guidance has been structured to accommodate a wide range of Partners with varying levels of information, and measurements in various units. If the Partner has a CEMS installed or has carbon content data based on fuel sampling information, they should refer to guidance in 40 CFR Part 75 to calculate CO_2 emissions. In the case of those with more than one exhaust stack, such as those with a heat recovery system generator (HRSG) or duct burner, a CEMS may not account for all combustion emissions.

5.1. Activity Data Source

When calculating CO_2 emissions with the fuel analysis approach, the first piece of information that needs to be determined is the quantity of fuel combusted. One method of determining the amount of fuel combusted at a facility is to measure the fuel input into each combustion device and to sum the measured data of each combustion device in the facility. Typical fuel measurement systems measure the volume of fuel combusted, such as fuel flow meters for natural gas and diesel, or the weight of fuel combusted, such as coal feed belt scales. If fuel use data is not directly measured then fuel purchase records can be used to estimate the amount of fuel combusted.

There are several factors that could lead to differences between the amount of fuel purchased and the amount of fuel combusted during a reporting period, for example:

■ Changes in fuel storage inventory

■ Fugitive releases or spills of fuel

■ Fuel used as feedstock

For changes in fuel storage inventory, Equation 3 can be used to convert fuel purchase data to estimates of actual fuel use:

Equation 3: Accounting for Changes in Fuel Inventory

Fuel B = Fuel P + (Fuel S_T – Fuel S_E)

where:

Fuel B   = Fuel burned in reporting period

Fuel P   = Fuel purchased in reporting period

Fuel S_T = Fuel stock at start of reporting period

Fuel S_E = Fuel stock at end of reporting period

Fuel purchase data is usually reported as the amount of fuel provided by a supplier as it crosses the gate of the facility. However, once fuel enters the facility there could be some losses before it actually reaches the combustion device. These losses are particularly important for natural gas, which could be lost due to fugitive releases from facility valves and piping, as these fugitive emissions could be significant. These fugitive natural gas releases (essentially methane emissions) should be accounted for separately from combustion emissions.

Purchased fuels could also be used as feedstock for products produced by the reporting entity. In this case the carbon in the fuel would be stored in the product as opposed to being released through combustion. Climate Leaders

Partners are only responsible for direct emissions at their facilities, if carbon leaves the facility stored in a product it should not be counted as a release even if the product is subsequently burned or otherwise releases the stored carbon. Therefore, Partners should subtract any amount of fuel that is used as feedstock from the amount of fuel purchased before calculating emissions.

5.2. Activity Data Units

Fuel is metered in terms of physical units (i.e., mass or volume) and it is recommended that Partners track fuel use in terms of these physical units as they represent the primary measurement data. However, Partners that do not directly measure how much fuel they use need to rely on data from fuel suppliers. Furthermore, fuel purchasers are mostly interested in the amount of fuel they purchase in terms of energy units and may not obtain data on the physical quantities of fuel used. Therefore, it is recommended that Partners obtain data on the physical quantities of fuel purchased as well as the heating values used to convert these physical quantities into energy values from fuel suppliers. It is also recommended that Partners use fuel supplier or analysis heating values over the default heating values listed in Appendix B to convert fuel use in physical units into energy units, as these values should better represent the characteristics of the specific fuel consumed. It is also good practice to track these heating values and indicate if they are variable, updated over time, etc.

It is possible that Partners may only know the dollar amount spent on a type of fuel, however, this is the least accurate method of determining fuel use and is not recommended for Climate Leaders reporting. If dollar amount spent on fuel is the only information available, it is recommended that Partners contact their fuel supplier to get more information. If absolutely no other information is available, Partners should be very clear on how price data is converted to physical or energy units. Price varies widely for a specific fuel, especially over the spatial and time frames typically established for reporting CO_2 emissions (e.g., entity wide reporting on an annual basis for Climate Leaders).

The approaches for measuring or recording the amount of fuel used are listed in order of preference below.

1. Partner has fuel quantity purchased data by fuel type in terms of physical units either measured on site or provided from supplier with accurate data on heat content of the specific fuel as determined by the fuel supplier or through measurement or testing.

2. Partner has data on the physical quantity of fuel purchased but not the heat content so the Partner must apply default fuel heat content values.

3. Partner only has data on dollar amount of fuels purchased and has to convert to physical quantity based on dividing total expenditures by average prices, and the Partner must apply default fuel heat content values.

5.3. Emission Calculation Factors

Once the amount of fuel combusted is determined, the next step in calculating CO_2 emissions is to determine how much carbon is in the fuel. Emissions of CO_2 from fuel combustion are dependent on the amount of carbon in the fuel, which is specific to the fuel type and grade of

the fuel. The most accurate method to determine a fuel's carbon content data is through chemical analysis of the fuel. This data may be obtained directly from the fuel supplier. If the specific carbon content of a fuel is not measured, default values could be used. Default values for the carbon content of fuels are available by physical units (e.g., percent carbon and by weight or volume), however these values vary widely by region of the country, time of year, fuel supplier, etc.

Fuel heat content data can be obtained from sampling and analysis or from the fuel supplier. Fuel suppliers often provide the heating value of a fuel with mass/volume measurements. Fuel purchasers are interested in the energy content of fuels purchased as it better represents the use of the fuel as opposed to mass or volume (fuel pricing is often based on energy, not physical units). Fuel heat content factors can be used to convert fuel use data in terms of physical units to fuel use data in terms of energy units as described in Section 5.2.

The Climate Leaders default fuel analysis approach for calculating CO_2 emissions from stationary combustion sources is based on a carbon factor per unit of fuel energy as shown in Section 2.2. Default values for fuel carbon content per energy units are provided in Appendix B. These carbon content factors per energy units are less variable than carbon content factors per physical units because the heat content or energy value of a fuel is more closely related to the amount of carbon in the fuel than to the total physical quantity of fuel.[6]

Not all stationary combustion devices burn standard fuels. Combustion devices could also burn waste fuels, for example, MSW with mixed biomass and fossil carbon content. Flares and thermal oxidizers could burn waste gas streams. These combustion sources and waste fuels are treated like other combustion sources and fuel types. Due to the variability and non-standardized nature of waste fuels, some guidance and sources of information on determining carbon content factors for waste fuels are provided in Appendix B, but the preferred approach is that Partners use factors specific to the waste fuels used.

A fuel's carbon content is never fully oxidized into CO_2 emissions through combustion. A portion of the carbon remains in the form of ash or unburned carbon. Consequently, it is necessary to use an oxidation factor when calculating CO_2 emissions from stationary combustion sources. Default oxidation factors to account for unburned carbon can be found in Appendix B. However, it is recommended that Partners use their own oxidation factors, if available, to better represent the fuel properties and the combustion device's operating characteristics. It is important to note that there are also intermediate combustion products from stationary combustion sources such as carbon monoxide (CO) and hydrocarbons that may eventually get oxidized into CO_2 in the atmosphere. The carbon oxidation factor does not account for carbon in these intermediate combustion products, but only the amount of carbon that remains as ash, soot or particulate matter.

After calculating a fuel's oxidized carbon content it is necessary to convert carbon into CO_2 emissions. A fuel's oxidized carbon is converted into CO_2 emissions by multiplying the carbon emissions by the molecular weight ratio of

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6 This relative accuracy is only true if the specific fuel heating value is known. If the default heating value is used to convert fuel use in terms of mass or volume to energy then the same result for carbon in the fuel would be derived from using default carbon content per mass or volume and carbon content per unit of energy.

Example: Determining an Emission Factor for a Gas Waste Stream

A Climate Leaders Partner has a thermal oxidizer destroying a waste gas stream of different components. The Partner has data on volume of gas combusted and on the mole fraction of the different components of the waste gas stream.

The first step is to determine the total number of moles in the waste stream per a specific volume. This is based on the assumed temperature and pressure of the gas. Assuming conditions of 1 atm and 25° C, there are 2.55×10^3 lbmole of gas per cubic foot of gas. This factor could be adjusted to meet the specific temperature and pressure conditions of the Partner's waste gas stream. An emission factor is then determined per cubic feet of gas based on the following Equation EX-1:

Equation EX-1: Determining Emission Factor for Gas Waste Stream

$$\text{Emission Factor} \left(\frac{\text{lb.C}}{\text{ft.}^3} \right) = \sum_{i=1}^{n} MF_i \times \text{Moles} \times m.w._i \times CF_i$$

where:

MF_i =   Molar Fraction of Gas Component i $\left(\dfrac{\text{lbmole i}}{\text{Moles}} \right)$

Moles =   Total Number of Moles in a Specific Volume of Gas Mixture $\left(\dfrac{\text{lbmole}}{\text{ft.}^3} \right)$

$m.w._i$ =   Molecular Weight of Gas Component i $\left(\dfrac{\text{lb. i}}{\text{lbmole i}} \right)$

CF_i =   Carbon Fraction of Gas Component i $\left(\dfrac{\text{lb.C}}{\text{lb.i}} \right)$

The following Table EX-1 shows an example gas waste stream with the mole fractions of different components.

Table EX-1: Example Gas Waste Stream

Gas Component	Mole %	lbmole	m.w.	% C	lb. C
CO_2	5%	1.28×10^4	44	27%	0.001531
CH_4	30%	7.66×10^4	16	75%	0.009188
C_3H_8	20%	5.10×10^4	44	82%	0.018376
C_6H_6	35%	8.93×10^4	78	92%	0.064315
Other non-C	10%	2.55×10^4	?	0%	0
Total	100%	2.55×10^3	—	—	0.093409

Based on Table EX-1 it can be seen that the emission factor for this example gas waste stream is 0.0934 lb. C per ft^3 of waste gas. This emission factor can be used in conjunction with the total amount of gas combusted as well as an oxidation factor and converted to CO_2 in order to obtain total emissions from waste gas combustion.

CO_2 to carbon (44/12). Whenever possible, customized factors for heating values, carbon content, and fraction of carbon oxidized for each fuel type should be used. Otherwise, default emission factors are provided in Appendix B.

Appendix B provides default factors for heating value, carbon content in terms of amount of carbon per energy value of fuel, and fraction of carbon oxidized for different fuels. Other sources of CO_2 emissions factors sometimes combine the different fuel and combustion elements into one emission factor value. For example, if the carbon content of the fuel is combined with the carbon oxidation factor and the carbon to CO_2 ratio, a CO_2 emission factor can be obtained in terms of mass of CO_2 per unit of fuel energy. Furthermore, if the carbon content factor is combined with the default

heat content of the fuel and the fraction carbon oxidized as well as the carbon to CO_2 ratio, a CO_2 emission factor can be obtained in terms of mass of CO_2 per mass or volume unit of fuel.

If one of these alternate emissions factors is used, care should be taken to determine the source of the data and what it represents (e.g., published factors may assume a carbon oxidation factor other than 100%). Values are provided in Appendix B for CO_2 emission factors in terms of energy and mass/volume fuel units. These were created based on the Climate Leaders default values provided for heating value, carbon content in terms of amount of carbon per energy value of fuel, and fraction of carbon oxidized for different fuels.

Example: Measuring Fuel Use in Energy Units — Lower and Higher Heating Values

When measuring fuel use data in energy units, it is important to distinguish between lower heating values (LHV) and higher heating values (HHV) (also called net and gross calorific values respectively). Heating values describe the amount of energy released when a fuel is burned completely, and LHVs and HHVs are different methods to measure the amount of energy released.[7] A given fuel, therefore, always has two heating value numbers, a LHV and a HHV number. Whereas HHVs are typically used in the U.S. and in Canada, other countries use LHVs. To convert from LHV to HHV, a simplified convention used by the International Energy Agency can be used. For coal and petroleum, divide energy in LHV by 0.95. For natural gas, divide by 0.90.

For example, natural gas has a LHV of 924 Btu/standard cubic foot (scf) and a HHV of 1,027 Btu/scf. When calculating CO_2 emissions by multiplying fuel use data in energy units by a carbon content coefficient, it is important to be mindful of LHV or HHV specific coefficients in the emissions calculation. The LHV specific carbon content coefficient for natural gas is 16.08 kg C/mmBtu and the HHV specific carbon content coefficient is 14.47 kg C/mmBtu.

Therefore, to calculate CO_2 emissions from burning 1 million scf of natural gas:

Based on LHV:

$$1 \times 10^6 \text{ scf} \times \frac{924 \text{ Btu}}{\text{scf}} \times \frac{1 \text{ mmBtu}}{1 \times 10^6 \text{ Btu}} \times \frac{16.08 \text{ kg C}}{\text{mmBtu}} \times \frac{44 \text{ kg CO}_2}{12 \text{ kg C}} = 54{,}479 \text{ kg CO}_2$$

Based on HHV:

$$1 \times 10^6 \text{ scf} \times \frac{1{,}027 \text{ Btu}}{\text{scf}} \times \frac{1 \text{ mmBtu}}{1 \times 10^6 \text{ Btu}} \times \frac{14.47 \text{ kg C}}{\text{mmBtu}} \times \frac{44 \text{ kg CO}_2}{12 \text{ kg C}} = 54{,}489 \text{ kg CO}_2$$

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7 The heating value is dependent on the phase of water/steam in the combustion process. Higher heating value is the heat evolved when all of the products of combustion are cooled to atmospheric temperature and pressure. The lower heating value is the heat evolved when the products of combustion are cooled so that water remains as a gas. HHVs are around 105% of LHVs; for natural gas, the factor is 110%.

Completeness

In order for a Partner's GHG corporate inventory to be complete it must include all emission sources within the company's chosen inventory boundaries. See Chapter 3 of the *Climate Leaders Design Principles* for detailed guidance on setting organizational boundaries and Chapter 4 of the *Climate Leaders Design Principles* for detailed guidance on setting operational boundaries of the corporate inventory.

On an organizational level the inventory should include emissions from all applicable facilities or fleets of vehicles. Completeness of corporate wide emissions can be checked by comparing the list of sources included in the GHG emissions inventory with those included in other emission's inventories, environmental reporting, financial reporting, etc.

At the operational level, a Partner should include all GHG emissions from the sources included in their corporate inventory. Possible GHG emission sources are stationary fuel combustion, combustion of fuels in mobile sources, purchases of electricity, HFC emissions from air conditioning equipment and process or fugitive related emissions. Partners should refer to this guidance document for calculating emissions from stationary combustion sources and to the Climate Leaders Core Guidance documents for calculating emissions from other sources.

Operational completeness of stationary combustion sources can be checked by comparing the sources included in the GHG inventory with those reported under regulatory programs (e.g., Title V air permit), or in annual fuel use surveys. Examples of typical types of fuel combustion sources that should be included are as follows:

- Boilers/furnaces

- Internal combustion engines

- Turbines

- Flares

- Process heaters/ovens

- Incinerators

- Cooling systems (e.g., natural gas chillers)

As described in Chapter 1 of the *Climate Leaders Design Principles*, there is no materiality threshold set for reporting emissions. The materiality of a source can only be established after it has been assessed. This does not necessarily require a rigorous quantification of all sources, but at a minimum, an estimate based on available data should be developed for all sources.

The inventory should also accurately reflect the timeframe of the report. In the case of Climate Leaders, the emissions inventory is reported annually and should represent a full year of emissions data.

Uncertainty Assessment

There is uncertainty associated with all methods of calculating CO_2, CH_4, and N_2O emissions from stationary combustion sources. As outlined in Chapter 7 of the *Climate Leaders Design Principles*, Climate Leaders does not require Partners to quantify uncertainty as +/- % of emissions estimates or in terms of data quality indicators.

It is recommended that Partners attempt to identify the areas of uncertainty in their emissions estimates and make an effort to use the most accurate data possible. If the CEMS approach is used to estimate emissions, it is recommended that the Partner follow the QA/QC guidance and good practices associated with that method as outlined in the Acid Rain Program Rule[8]. Entities utilizing CEMS to comply with Clean Air Act regulations are required to develop a quality assurance plan. This plan should address CO_2 emissions measurement.

The accuracy of estimating emissions from fossil fuel combustion in stationary sources from the fuel analysis approach is partially determined by the availability of data on the amount of fuel consumed or purchased. If the amount of fuel combusted is directly measured or metered before entering the combustion device, then the resulting uncertainty should be fairly low. Data on the quantity of fuel purchased should also be an accurate representation of fuel combusted, given that any necessary adjustments are made for changes in fuel inventory, fuel used as feedstock, etc. However, uncertainty may arise if only dollar value of fuels purchased is used to estimate fuel consumption.

The accuracy of estimating emissions from stationary combustion sources with the fuel analysis approach is also determined by the factors used to convert fuel use into emissions. Uncertainty in the factors is primarily due to the accuracy in which they are measured, and the variability of the supply source. For example, carbon content factors for coal vary greatly, depending on its characteristics, chemical properties, and annual fluctuations in the fuel quality. Therefore, using the U.S. default carbon content coefficient for coal may result in a more uncertain estimate than for other fuels if the local fuel supplies do not match the default fuel characteristics.

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8 Part 75.21 and Appendix B of the regulation discuss the QA/QC plan.

Reporting and Documentation

Partners are required to complete the Climate Leaders *Reporting Requirements* and report annual corporate level emissions. In order to ensure that estimates are transparent and verifiable, the documentation sources listed in Table 1 should be maintained. These documentation sources should be collected to ensure the accuracy and transparency of the related emissions and should be reported in the Partner's Inventory Management Plan (IMP).

For both the CEMS and fuel analysis approaches, it is recommended that Partners measure the CO_2 emissions and supporting data by facility (as opposed to aggregated entity wide emissions only). This method increases the accuracy and credibility of the inventory.

Table 1: Documentation Sources for Stationary Combustion

Data	Documentation Source
Fuel consumption data[9]	Purchase receipts, delivery receipts, contract purchase or firm purchase records, stock inventory documentation, metered fuel documentation
Heat contents and emission factors used other than defaults provided	Purchase receipts; delivery receipts; contract purchase or firm purchase records; EIA, EPA or industry reports
Prices used to convert dollars of fuel purchased to amount or energy content of fuel consumed	Purchase receipts; delivery receipts; contract purchase or firm purchase records; EIA, EPA or industry reports
All assumptions made in estimating fuel consumption, heat contents, and emission factors	All applicable sources

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9 If purchase receipts, delivery receipts, etc. are used to proxy fuel consumption data then feedstock use has to be taken into account; otherwise, there is an overestimation of emissions.

Inventory Quality Assurance and Quality Control

Chapter 7 of the *Climate Leaders Design Principles* provides general guidelines for implementing a QA/QC process for all emission estimates. For stationary combustion sources, activity data and emission factors can be verified using a variety of approaches:

■ Fuel consumption data by source or facility can be compared with fuel purchasing data, taking into account any changes in inventory.

■ Fuel energy use data can be compared with data provided to Department of Energy or other EPA reports or surveys.

■ If emission estimates were obtained from CEMS, this data can be compared to emissions estimated using the fuel analysis approach.

■ If any emission factors were calculated or obtained from the fuel supplier, these fac-

tors can be compared to U.S. average emission factors.

■ The rate at which suppliers change/update heating values can be examined to approximate accuracy.

■ Depending on the end-use, some non-energy uses of fossil fuels, such as for manufacturing plant feedstocks, can result in long term storage of some or all of the carbon contained in the fuel. This guidance addresses fuels use for combustion purposes only. Therefore, all fuel consumption for other purposes should be excluded from this analysis.

■ Examining the quality control associated with equipment used for facility level fuel measurements and equipment used to calculate site-specific emissions factors, or emissions.

Appendix A: Calculating CH_4 and N_2O Emissions from Stationary Combustion Sources

As mentioned earlier, CH_4 and N_2O emissions depend not only on fuel characteristics but also on technology type, combustion characteristics and control technology. The emission factors provided in Table A-1 are those used by the U.S. EPA when calculating the national GHG inventory[10]

and are the emission factors recommended by the Intergovernmental Panel on Climate Change (IPCC) 2006 Guidelines[11]. The emission factors for pulping liquors are from the National Council for Air and Stream Improvement, Inc.[12] The emission factors were converted from g/GJ to g/mmBtu based on the

Table A-1: CH_4 and N_2O Emission Factors by Fuel Type and Sector

Fuel/End-Use Sector	CH_4 (g/GJ–HHV)	N_2O (g/GJ–HHV)	CH_4 (g/mmBtu)	N_2O (g/mmBtu)
Coal				
– Residential	300	1.5	316	1.6
– Commercial	10	1.5	11	1.6
– Industry	10	1.5	11	1.6
– Electricity Generation	1	1.5	1	1.6
Petroleum				
– Residential	10	0.6	11	0.6
– Commercial	10	0.6	11	0.6
– Industry	3	0.6	3	0.6
– Electricity Generation	3	0.6	3	0.6
Natural Gas				
– Residential	5	0.1	5	0.1
– Commercial	5	0.1	5	0.1
– Industry	1	0.1	1	0.1
– Electricity Generation	1	0.1	1	0.1
Wood				
– Residential	300	4	316	4.2
– Commercial	300	4	316	4.2
– Industry	30	4	32	4.2
– Electricity Generation	30	4	32	4.2
Pulping Liquors				
– Industry	2.4	1.9	2.5	2.0

10 U.S. Environmental Protection Agency 2007. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2005.* EPA 430-R-07-002.

11 Intergovernmental Panel on Climate Change (IPCC). 2006. *Guidelines for National Greenhouse Gas Inventories,* Intergovernmental Panel on Climate Change, Organization for Economic Co-Operation and Development. Paris, France.

12 National Council for Air and Stream Improvement, Inc. (NCASI), 2004 Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills. Version 1.1, Research Triangle Park, NC.

conversion factor of 0.95 mmBtu/GJ to be more consistent with other factors presented in these guidelines.

The factors provided in Table A-1 represent emissions in terms of fuel type and end-use sectors (i.e., residential, commercial, industrial, electricity generation). Other references, including those listed below, are emission factors by more specific combustion technology type (e.g., natural gas industrial boilers >293 MW). These references are recommended for Partners interested in performing a more accurate estimate of CH_4 and N_2O emissions.

■ U.S. EPA 1995. *Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Area Sources*, 5th edition, Supplements A, B, C, D, E, F, Updates 2001, 2002 & 2003, AP-42, U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

■ State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (STAPPA/ALAPCO) and the U.S. EPA. *Emissions Inventory Improvement Program (EIIP) Vol. VIII, Chapter 2, Methods For Estimating Methane And Nitrous Oxide Emissions From Stationary Combustion*, August 2004.

Appendix B: Default Factors for Calculating CO_2 Emissions

This appendix contains default factors for use in calculating CO_2 emissions from the fuel analysis approach described by in Section 2.2 of this document.

Table B-1 contains default Heat Contents, Carbon Content Coefficients, and Fraction of Carbon Oxidized for different fossil fuels to be used in this approach.

Table B-1: Default Factors for Calculating CO_2 Emissions from Fossil Fuel Combustion

Fossil Fuel	Heat Content (HHV)	Carbon Content Coefficients	Fraction Oxidized
Coal and Coke	(mmBtu/ton)	(kg C/mmBtu)	
Anthracite Coal	25.09	28.26	1.0
Bituminous Coal	24.93	25.49	1.0
Sub-bituminous Coal	17.25	26.48	1.0
Lignite	14.21	26.30	1.0
Unspecified (industrial coking)	26.27	25.56	1.0
Unspecified (industrial other)	22.05	25.63	1.0
Unspecified (electric utility)	19.95	25.76	1.0
Unspecified (residential/commercial)	22.05	26.00	1.0
Coke	24.80	31.00	1.0
Natural Gas	(Btu/scf)	(kg C/mmBtu)	
Natural Gas	1,029	14.47	1.0
Petroleum	(mmBtu/Barrel)	(kg C/mmBtu)	
Distillate Fuel Oil (#1, 2, & 4)	5.8250	19.95	1.0
Residual Fuel Oil (#5 & 6)	6.2870	21.49	1.0
Kerosene	5.6700	19.72	1.0
Petroleum Coke	6.0240	27.85	1.0
LPG (average for fuel use)	3.8492	17.23	1.0
Common LPG Components:			
Ethane	2.9160	16.25	1.0
Propane	3.8240	17.20	1.0
Isobutane	4.1620	17.75	1.0
n-Butane	4.3280	17.72	1.0
Waste Tires	(mmBtu/ton)	(kg C/mmBtu)	
Waste Tires	28.00	30.77	1.0

Note:

Values for fuels may change over time so it is recommended that Partners update factors on a regular basis. Factors shown here are appropriate for years 2000–2005.

Sources:

Coal—Carbon Content Coefficients from the *Documentation for Emissions of Greenhouse Gases in the United States 2005*, DOE/EIA-0573(2005), Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, November 2006. Heat Contents calculated by EPA based on the same approach used to determine Carbon Content Coefficients. The approach utilizes coal physical characteristics from the *CoalQual Database Version 2.0*, U.S. Geological Survey, 1998, and coal production data from the *Annual Coal Report 2005*, U.S. Department of Energy, Energy Information Administration, Washington DC. As well as coal heat content information from the *Annual Energy Review 2006*, U.S. Department of Energy, Energy Information Administration, Washington, DC. Fractions Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007.

Coke—Heat Content from the *Annual Energy Review 2006*, U.S. Department of Energy, Energy Information Administration, Washington, DC. Carbon Content Coefficient and Fraction Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007.

Natural Gas and Petroleum (except LPG)—Heat Contents from the *Annual Energy Review 2006*, U.S. Department of Energy, Energy Information Administration, Washington, DC. Carbon Content Coefficients and Fractions Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007.

LPG—Carbon Content Coefficients for LPG components from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007. Carbon Content Coefficient value for LPG from *Annual Energy Review 2006*, U.S. Department of Energy, Energy Information Administration, Washington, DC. Heat Content value for LPG and its components from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*. EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007. Fractions Oxidized also from the EPA inventory report. The Fractions Oxidized for LPG components are assumed to be the same as for LPG.

If a partner knows the specific blend of LPG that they are using, heat content and carbon content coefficients for different blends of LPG can be calculated based on the percent mix and individual component characteristics shown in Table B-1.

Table B-2 contains default Heat Contents, Carbon Content Coefficients, and Fraction of Carbon Oxidized for different non-fossil fuels to be used in the fuel analysis approach.

Table B-2: Default Factors for Calculating CO_2 Emissions from Non-Fossil Fuel Combustion

Non-Fossil Fuel	Heat Content (HHV)	Carbon Content Coefficients	Fraction Oxidized
Solid	(mmBtu/ton)	(kg C/mmBtu)	
Wood and Wood Waste (12% moisture)	15.38	25.60	1.0
Kraft Black Liquor (North American hardwood)	11.98	25.75	1.0
Kraft Black Liquor (North American softwood)	12.24	25.95	1.0
Gas	(Btu/scf)		
Landfill Gas (50% CH_4/50% CO_2)	502.50	14.20	1.0
Wastewater Treatment Biogas	varies	14.20	1.0

Sources:

Wood and Wood Waste—Heat Content and Carbon Content Coefficient from *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA 430-R-07-002, U.S. Environmental Protection Agency, Washington, DC April 2007. Chapter 3 text describing the methodology used to calculate emissions from Wood Biomass and Ethanol Consumption. Heat Content is assumed to be representative of wood and wood waste used in the industrial sector. Carbon Content Coefficient calculated from the value listed, 434 kg C/metric ton, and the assumed heat content. Fraction Oxidized also from the EPA inventory report and assumed to be the same as for coal combustion. The factors presented in Table B-2 represent emissions from wood combustion only and do not include any emissions or sinks from wood growth or harvesting.

Gas—Heat Content for landfill gas based on heat content of methane, 1,005 Btu/standard ft³, and assumed landfill gas composition of 50% CH_4 and 50% CO_2 by volume. Heat Content for wastewater treatment gas can be calculated based on methane heat content and percent methane in the gas. Carbon Content Coefficients represent pure methane. Fraction Oxidized from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*. EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007 and assumed to be the same as for natural gas.

Kraft Black Liquor—Black liquor default emission factors based on the carbon content of the liquors and include any carbon exiting with smelt from a recovery furnace. Therefore, for kraft mills, the liquor emission factors estimate biomass carbon emissions from both the recovery furnace and from the lime kiln. The emission factors from *International Council of*

Forest and Paper Associations (ICFPA) and the National Council for Air and Stream Improvement (NCASI) spreadsheets for calculating GHG emissions from pulp and paper manufacturing (Version 1.2). (The ICFPA/NCASI tool assumes a 1% correction for unoxidized carbon, the emission factors in this guidance document assume 100% of the carbon is oxidized). Black liquor data for the ICFPA/NCASI tool were obtained from: Chapter 1-Chemical Recovery, by Esa Vakkilainen, 1999. In: Papermaking Science and Technology, Book 6B: Chemical

Pulping. Gullichsen, J., and Paulapuro, H. (eds.). Helsinki, Finland: Fapet Oy.

Waste Tires—Heat content for waste tires from *Rubber Manufacturers Association (RMA), Scrap Tire Markets in the United States, November 2006.* The carbon content for waste tires from the *Inventory of U.S. Greenhouse Gas Emissions and Skinks: 1990-2005.* EPA430-R-07-002, U.S. EPA, Washington, DC, April 2007.

CO$_2$ Emissions Factors Based on Fuel Energy

Sources of CO$_2$ emissions factors sometimes combine the different fuel and combustion elements into one emission factor value. For example, if the carbon content of the fuel is combined with the carbon oxidation factor and the carbon to CO$_2$ ratio, a CO$_2$ emission factor can be obtained in terms of mass of CO$_2$ per unit of fuel energy.

Therefore, the default factors shown in Tables B-1 and B-2 can be combined (with the CO$_2$/C ratio of 44/12) to determine emission factors in terms of mass of CO$_2$ per unit of fuel energy. Table B-3 contains default heat content and emission factors for different fossil fuels and Table B-4 contains default heat content and emission factors for different non-fossil fuels as calculated from the default factors listed previously.

Table B-3: CO$_2$ Emission Factors (mass CO$_2$/fuel energy) for Fossil Fuel Combustion

Fossil Fuel	Heat Content (HHV)	CO$_2$ Content Coefficient
Coal and Coke	(mmBtu/ton)	(kg CO$_2$/mmBtu)
Anthracite Coal	25.09	103.62
Bituminous Coal	24.93	93.46
Sub-bituminous Coal	17.25	97.09
Lignite	14.21	96.43
Unspecified (industrial coking)	26.27	93.72
Unspecified (industrial other)	22.05	93.98
Unspecified (electric utility)	19.95	94.45
Unspecified (residential/commercial)	22.05	95.33
Coke	24.80	113.67
Natural Gas	(Btu/scf)	(kg CO$_2$/mmBtu)
Natural Gas	1,029	53.06
Petroleum	(mmBtu/Barrel)	(kg CO$_2$/mmBtu)
Distillate Fuel Oil (#1, 2, & 4)	5.8250	73.15
Residual Fuel Oil (#5 & 6)	6.2870	78.80
Kerosene	5.6700	72.31
Petroleum Coke	6.0240	102.12
LPG (average for fuel use)	3.8492	63.16
Common LPG Components:		
Ethane	2.9160	59.58
Propane	3.8240	63.07
Isobutane	4.1620	65.08
n-Butane	4.3280	64.97
Waste Tires	(mmBtu/ton)	(kg CO$_2$/mmBtu)
Waste Tires	28.00	112.84

Table B-4: CO$_2$ Emission Factors (mass CO$_2$/fuel energy) for Non-Fossil Fuel Combustion

Fossil Fuel	Heat Content (HHV)	CO$_2$ Content Coeffecient
Solid	(mmBtu/ton)	(kg CO$_2$/mmBtu)
Wood and Wood Waste (12% moisture)	15.38	93.87
Kraft Black Liquor (North American hardwood)	11.98	94.41
Kraft Black Liquor (North American softwood)	12.24	95.13
Gas	(Btu/scf)	
Landfill Gas (50% CH$_4$/50% CO$_2$)	502.50	52.07
Wastewater Treatment Biogas	varies	52.07

CO$_2$ Emissions Factors Based on Fuel Mass or Volume

If the carbon content factor is combined with the default heat content of the fuel, fraction carbon oxidized, and carbon to CO$_2$ ratio, a CO$_2$ emission factor can be obtained in terms of mass of CO$_2$ per mass or volume unit of fuel.

Therefore, the default factors shown in Tables B-3 and B-4 can be combined with the heat content of the fuels to determine emission factors in terms of mass of CO$_2$ per unit of fuel mass or volume. Table B-5 contains default emission factors for different fossil fuels and Table B-6 contains default emission factors for different non-fossil fuels as calculated from the default factors listed previously.

Table B-5: CO$_2$ Emission Factors (mass CO$_2$/fuel mass or volume) for Fossil Fuel Combustion

Fossil Fuel	Emission Factor
Coal and Coke	(kg CO$_2$/ton)
Anthracite Coal	2,599.83
Bituminous Coal	2,330.04
Sub-bituminous Coal	1,674.86
Lignite	1,370.32
Unspecified (industrial coking)	2,462.12
Unspecified (industrial other)	2,072.19
Unspecified (electric utility)	1,884.53
Unspecified (residential/commercial)	2,102.29
Coke	2,818.93
Natural Gas	(kg CO$_2$/scf)
Natural Gas	0.0546
Petroleum	(kg CO$_2$/Barrel)
Distillate Fuel Oil (#1, 2, & 4)	426.10
Residual Fuel Oil (#5 & 6)	495.39
Kerosene	409.98
Petroleum Coke	615.15
LPG (average for fuel use)	243.12
Common LPG Components:	
Ethane	173.75
Propane	241.17
Isobutane	270.88
n-Butane	281.20
Waste Tires	(kg CO$_2$/ton)
Waste Tires	3,159.49

Table B-6: CO$_2$ Emission Factors (mass CO$_2$/fuel mass or volume) for Non-Fossil Fuel Combustion

Fossil Fuel	Emission Factor
Solid	(kg CO$_2$/ton)
Wood and Wood Waste (12% moisture)	1,443.67
Kraft Black Liquor (North American hardwood)	1,130.76
Kraft Black Liquor (North American softwood)	1,164.02
Gas	
Landfill Gas (50% CH$_4$/50% CO$_2$)	0.0262
Wastewater Treatment Biogas	varies

Waste Fuels

Emissions from combustion of waste fuels of both fossil and biomass origin are treated the same as emissions of other fossil or biomass fuels. No specific default values for carbon content of waste fuels are provided due to the variability of the different waste fuels.

The cement industry in particular is a large user of waste fuels. Guidance developed by that industry for calculating emissions has specific default values to calculate emissions for different waste fuels. *CO₂ Accounting and Reporting Standard for the Cement Industry,* Version 2.0, June 2005, World Business Council for Sustainable Development.

The U.S. EPA also has data on waste fuel combustion that is used to calculate the National Inventory of GHG emissions. *Inventory of U.S. Greenhouse Gas Emissions and Sinks:*

1990–2005, EPA 430-R-07-002, U.S. Environmental Protection Agency, Washington, DC April 2007.

Annex 3, Section 3.6, of the U.S. EPA inventory report has information on emissions from combustion of Municipal Solid Waste (MSW).

Emission factors for some waste fuels can be determined by taking the emission factor that most closely represents the waste fuel. For example, using the factor for fuel oil to represent waste oil combustion. In general however, Climate Leaders encourages the use of the most accurate methodologies. The data quality tiers that should be used for any fuel combustion in stationary sources are: (a) direct monitoring, (b) mass balance using actual fuel characteristics data, (c) mass balance using a combination of actual and default fuel characteristics data and (d) default CO_2 emission factors by fuel type.

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